UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
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UNDERGROUND INJECTION CONTROL (UIC)

FINAL MAJOR MODIFICATION

Date Prepared: June 2012

CLASS I
NON-HAZARDOUS INDUSTRIAL WASTE DISPOSAL WELL

Permit No. CO10789-00420

WOODS NO. 3 (MWD-1)
McELMO DOME FIELD

County & State: Montezuma County, Colorado

Issued To:

KINDER MORGAN CO_2 COMPANY LP
17801 Hwy 491
Cortez, CO 81321

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PART I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control (UIC) Regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 146, and 147,

Kinder Morgan CO_2 Company, LP
17801 Hwy 491
Cortez, CO 81321

hereby referred to as the "Permittee" is reauthorized to operate a Class I injection well, commonly known as **Woods No. 3 (MWD-1)** located at 2,800 feet (ft) from the south line and 600 ft from the east line of Section 16, Township 37 North, Range 17 West, Montezuma County, Colorado. Injection shall be for the purpose of industrial waste fluid disposal into the following formations: Leadville, 7,776 ft – 8,046 ft; Ouray, 8,046 ft – 8,122 ft; and the Undifferentiated Devonian and Cambrian Formations, 8,122 ft – 8,900 ft, in accordance with conditions set forth herein.

This permit major modification includes certain modifications of the original permit and reauthorizations and shall continue operations upon the receipt of approval from the Environmental Protection Agency (EPA) UIC Program, to resume injection. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. "Transition from Expiring Permit to Permit Re-Authorization" requirements are set forth in Part III, Section B.3 of this permit.

EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State, or local laws or regulations (40 CFR 144.35)

All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations and are regulations that are in effect on the date that this permit becomes effective.

This major permit modification continues to be issued for **ten (10) years from the 2009 re-issuance**, unless terminated. The permit will be reviewed at least every five years to determine whether action under 40 CFR 144.36(a) is warranted. The permit will expire at **midnight**

October 31, 2019, or upon delegation of primary enforcement responsibility for the UIC 1422 Program to the State of Colorado, unless that State has adequate authority and chooses to adopt and enforce this permit as a State permit.

Reauthorized and issued this 21 day of June 2012

This permit becomes effective JUN 22 2012.

for

Callie A. Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONSTRUCTION REQUIREMENTS

1. Casing and Cementing.
The construction diagram submitted with supplemental information for the major modification application is hereby incorporated into this permit as APPENDIX A, and shall be binding on the Permittee. The Permittee has cased and shall additional cement to the well to prevent the movement of fluids into or between underground sources of drinking water (USDWs). The casing and cement used in the construction of the well have been designed for the life expectancy of the well, and shall be maintained throughout the operating life of the well.

2. Tubing and Packer Specifications.
Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the permittee provides notice and obtains the Director's approval for the change. The applicant submitted details on the tubing and packer in the application; these are incorporated into the permit as APPENDIX A, and shall be binding on the Permittee.

   Injection between the outermost casing protecting an underground source of drinking water (e.g. surface casing, production casing, and liner) and the wellbore is prohibited. Injection directly through the casing (i.e. without tubing) is also prohibited.

3. Sampling and Monitoring Devices.
The Permittee shall install and maintain in good operating condition:

   a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

   b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX E:

      (i) on the injection tubing; and

      (ii) on the tubing-casing annulus (TCA); and

c) a pressure actuated shut-off device attached to the injection flow line set to shut in the well when or before the Maximum Allowable Injection Pressure specified in APPENDIX E is reached at the wellhead; and

d) a non-resettable cumulative volume recorder attached to the injection line; and

e) a continuous recording device(s) to monitor injection pressure, flow rate, volume, and the pressure on the annulus between the tubing and the long string of casing.

4. <u>Well Logging and Testing</u>.

Well logging and testing requirements are found in APPENDIX D. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX D. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director **within sixty (60) days** of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

At a minimum well logs shall include a description of deviation checks performed on all holes constructed by first drilling a pilot hole, and then enlarging the pilot hole by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling. Deviation checks are not required for existing wells which are being altered, recompleted, and/or converted.

5. <u>Postponement of Construction or Conversion</u>.

The Permittee shall complete (or recomplete) well construction within one year of the Effective Date of the Permit. Authorization to construct and operate shall expire if the well has not been constructed **within one (1) year** of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR Section 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. <u>Proposed Changes and Workovers</u>.

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA **within sixty (60) days** of completion of the activity.

B. CORRECTIVE ACTION

No wells were identified in the Area of Review. Therefore, the operator is not required to take corrective action following the effective date of this modified permit.

C. MECHANICAL INTEGRITY

1. Mechanical Integrity.
The Permittee is required to ensure that each injection well maintains mechanical integrity at all times. Pursuant to 40 CFR 146.8, an injection well has mechanical integrity if it has:

Internal (or Part I) Mechanical Integrity (MI):
There is no significant leak in the casing, tubing, or packer. Internal MI generally is demonstrated by pressure testing the well to identify leaks; and

External (or Part II) MI:
There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection well bore. External MI involves evaluating the integrity of the cement behind the casing to find fluid channels or leaks, which is done using a temperature log or noise log.

Other UIC regulations which may apply include: 40 CFR 146.13.

2. Demonstration of MI.

The operator shall demonstrate Internal and External MI initially and periodically thereafter, as described in APPENDIX D. The operator shall demonstrate Internal MI after any workover which affects the tubing, packer, or casing. The Director may stipulate specific test methods and criteria best suited for the specific well construction and injection operation. Well-specific conditions present at this well site that dictate the specific method(s) and frequency required for demonstrating MI, are discussed in the Statement of Basis. The method(s) and frequency required, designed to demonstrate both Internal (Part I) and External (Part II) MI, are listed in APPENDIX D of this Permit.

The Director, by written notice, may require the Permittee to comply with a schedule describing when MI demonstrations shall be made. The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director.

3. Mechanical Integrity Test Methods and Criteria.
EPA-approved methods shall be used to demonstrate MI. The following EPA Region 8 guidance and guidelines may be accessed online at *http://www.epa.gov/region8/water/uic/deep_injection.html*, or will be provided to you upon request.

- ☐ "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity", *Ground Water Section Guidance No. 39*
- ☐ "Temperature Logging for Mechanical Integrity, January 12, 1999"
- ☐ "Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations," September 8, 2009

Kinder Morgan may fulfill Part II MI requirements by using one of the following options: Option 1: running a Temperature Log or Noise Log or Option 2: Running a Temperature Log with a Supplemental Radioactive Tracer Survey. Temperature Logs may be performed while the well operates on a vacuum or at normal operating conditions. When performing an RTS, the slug test may be performed on a vacuum or at normal operating conditions and the time drive test shall be performed at the assigned maximum allowed injection pressure (MAIP).

4. Notification Prior to Testing.
The Permittee shall notify the Director **at least thirty (30) days** prior to any scheduled MI test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the test. Notification may be in the form of a yearly or quarterly scheduled mechanical integrity test, or it may be on an individual basis.

5. Loss of Mechanical Integrity.
If the well fails to demonstrate MI during a test, or a loss of MI becomes evident during operation (such as presence of pressure in the tubing, casing, annulus (TCA), water flowing at the surface, etc), the Permittee shall notify the Director **within twenty-four (24) hours** (see Part III, Section E.11.(c) of this permit) and the well shall be shut-in **within forty-eight (48) hours** unless the Director requires immediate shut-in.

Within five (5) days of a loss of MI, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan. Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated MI, and the Director has provided written approval to resume injection.

D. WELL OPERATION

1. Requirements Prior to Continuation of Injection.
Well injection may continue only after all well construction or well recompletion and pre-injection requirements herein have been met and approved. The Permittee may not receive a final authorization to commence injection until

a) construction is complete, a successful Part I (Internal) and Part II (External) Mechanical Integrity Test (MIT), pore pressure measurement of the proposed injection zone, a completed Well Work Record Form 7520-12 and schematic, and applicable logging test data, identified in Appendix D, is received;

and

b) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

c) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well **within thirteen (13) days** of the date of the Director's receipt of the documentation specified in Part II, Section D.1.a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.
Injection is permitted only within the approved injection interval listed in APPENDIX E. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A.6.

3. Injection Pressure Limitation.

a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX E. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure cause the movement of injected or formation fluids into a USDW.

b) The pressure limit in paragraph (a) may be increased by the Director if the fracture pressure of the injection formation will not be exceeded, and the Permittee demonstrates that the proposed increase in surface pressure is necessary: (1) to overcome friction losses in the injection system, or (2) to inject the volume rate of fluid set by Part II, Section D.4., below. Either demonstration shall be made by performing a step rate test, using fluid normally injected, to determine both the instantaneous shut-in pressure (ISIP) and the formation breakdown pressure. The Director will determine any allowable increase based on the test results and other parameters reflecting actual injection operations.

c) Details of the proposed tests shall be submitted **at least seven (7) days** prior to the tests. Results of all tests shall be submitted to the Director **within ten (10) days** of the test. Injection at the increased pressure shall be approved by the Director, in writing, before the Permittee may begin continuous operations at the pressure.

d) Any approval by the Director for the increased pressure limitations as stated in paragraph (b) shall be made a part of this permit by minor modification without further opportunity for public comment.

4. Injection Volume-Rate Limitation.
Injection volume is limited to the volume specified in APPENDIX E.

5. Injection Fluid Limitation.
The Permittee is authorized to inject field and gas plant waste streams and other associated waste streams generated at the Permittee's McElmo Dome and Doe Canyon facilities. These waste streams shall be nonhazardous at the time of injection. This means that they shall not exhibit any hazardous characteristics under Subpart C (40 CFR Sections 261.20 thru 261.24). The present list of waste stream items is limited to:

a) spent sulfamic acid (2-8%) neutralized to a pH of 5 to 9 with soda ash or baking soda. This solution will also include a surfactant, a corrosion inhibitor and ammonium bifluoride;

b) acetic acid;

c) diethanolamine (DEA);

d) coolant drain-off (50% water, 50% diethylene glycol);

e) associated treatment chemicals, (e.g., antifreeze, corrosion inhibitor, and bacteria inhibitor);

f) potassium permanganate in potable water;

g) diethylene glycol;

h) produced/processed fluids; and

i) any non-hazardous fluids and/or treatment chemicals associated with field and plant development, operation and maintenance:

The above waste stream items generated at McElmo Dome and Doe Canyon are approved for injection. Prior to the injection of any additional waste streams, the Permittee shall notify the EPA and receive approval from the Director. The Permittee shall demonstrate that the character of the waste stream is not being significantly modified. At a minimum, this shall include pH, total dissolved solids (TDS) and specific gravity.

6. Tubing-Casing Annulus (TCA).
The tubing-casing annulus (TCA) shall be filled with water treated with corrosion inhibitor and oxygen scavenger, or other fluid approved by the Director. The permittee shall attempt to maintain zero (0) to twenty-five (25) pounds per square inch gauge (psig) pressure on the TCA.

If TCA pressure exceeds twenty-five (25) psi, the Permittee shall follow the procedures in *Ground Water Section Guidance No. 35,* "Procedures to follow when excessive annular pressure is observed on a well."

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program.
The Permittee submitted with the application a monitoring program, parts of which are incorporated into this permit as specified below.

Monitoring shall consist of:

a) analysis of the injection fluids, performed:

(i) **quarterly** for: pH, Total Dissolved Solids (TDS), and specific gravity;

(ii) The permittee shall submit a comprehensive water analysis and brief summary to the Director **within thirty (30) days** of observing any significant change(s) in the parameters measured under Part II, Section E.1.(a).(i) of this permit: pH, TDS, and specific gravity. The permittee shall identify the potential of any observed significant change(s) to cause fractures and/or of the potential of the injected fluid to exhibit a hazardous characteristic in the brief summary. A significant change observed for the parameters measured for the injection fluid are:

□ pH - Analysis of the fluid's pH value shows it to be less than 2 and/or greater than 12.5;

- ☐ TDS - Measured TDS values are 10% greater than the parameter's baseline value; and/or
- ☐ Specific Gravity - Specific gravity data is 10% greater than the parameter's baseline value.

The applicant shall use the baseline data previously established for the Woods No. 3 (MWD-1) well. Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize the applicable analytical methods described in Table I of 40 CFR Section 136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, other methods that have been approved by the EPA Administrator.

b) **weekly** observations and recordings of the injection pressure flow rate and volume. The monthly average, maximum, and minimum injection pressure, flow rate, and volume values shall be reported **quarterly** to the Denver EPA office, as per Part II, Section E.4.; and

c) **weekly** observations and recordings of the annulus pressure and annulus fluid level. The monthly average, maximum, and minimum annulus pressure values, as well as the annulus fluid level, shall be reported **quarterly** to the Denver EPA office, as per Part II, Section E.4.

2. Monitoring Information.
Records of any monitored activity required under this permit shall include:

a) the date, exact place, and time of sampling or field measurements;

b) the name of the individual(s) who performed the sampling or measurements;

c) the date(s) laboratory analyses were performed;

d) the name of the individual(s) who performed the analysis;

e) the analytical techniques or methods used by laboratory personnel; and

f) the results of such analyses.

3. Recordkeeping.
The Permittee shall retain records concerning: all monitoring information and copies of all reports required by this permit for a period of **at least three (3) years** from the date of the sample, measurement, or report, during the operating life of the well. Monitoring data will be kept in the local office of the Permittee. This period may be extended anytime prior to its expiration by request of the Director.

4. Reporting of Results.
The Permittee shall submit **Quarterly** Reports to the Director summarizing the results of the monitoring information required by Part II, Section E.1. of this permit. The Permittee shall also submit results of any mechanical integrity tests (MIT), any well workovers, logging, or testing that reveal conditions of the well or injection zone. These reports are due **within sixty (60) days** of the completion activity or at the time of the next quarterly report, whichever is sooner.

The first Quarterly Report shall cover the period from the effective date of the permit through the end of the quarter period. Subsequent **Quarterly** Reports shall cover the periods of: January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Each **Quarterly** Report shall be submitted to the Denver Office by the last day of the following month.

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment (P&A).
The Permittee shall notify the Director in writing **at least forty-five (45) days** prior to: plugging and abandoning an injection well and converting to a non-injection well.

2. Plugging and Abandonment Plan.
The Permittee shall plug and abandon the well as provided in the approved Plugging and Abandonment Plan. EPA reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may ask the Permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party (such as EPA) would incur to plug the well according to the plan. See the approved Plugging and Abandonment Plan in APPENDIX C of this permit. The Permittee shall submit a revised Plugging and Abandonment Plan which has been corrected to include correct depths once the well has been recompleted. The Permittee may provide three revised cost estimates if the Plugging and Abandonment Plan changes significantly, as well.

3. Cessation of Injection Activity.
After a cessation of injection for **two (2) years**, the Permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan unless the Permittee:

a) provides notice to the Director; and

b) demonstrates that the well will be used in the future; and

c) describes actions or procedures, satisfactory to the Director, that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report.
Within sixty (60) days after plugging the well, the Permittee shall submit a report on Form 7520-13 to the Director. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan, or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

G. FINANCIAL RESPONSIBILITY

1. Financial Responsibility.
The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency of Financial Institution.
In the event of:

a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

b) suspension or revocation of the authority of the trustee institution to act as trustee; or

c) the institution issuing the financial mechanism losing its authority to issue an instrument.

The Permittee shall notify the Director in writing, **within ten (10) business days**, and the Permittee shall establish other financial assurance or liability coverage acceptable to the Director **within sixty (60) days** after any event specified in (a), (b), or (c) above.

The Permittee shall also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, **within ten (10) business days** after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, shall make such a notification as required under the terms of the guarantee.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The Permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit or otherwise authorized by permit or rule is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination.
   The Director may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any permit condition.

2. Transfers.
   This permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR 144.38 are complied with. The Director may require modification, or revocation and reissuance, of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

3. Transition From Expiring Permit to Permit Reauthorization.
   This well has been operating by **permit** since **July 30, 1986** and reauthorizations issued in 1996 and 2009. Adherence to all requirements under 40 CFR Part 144, 146, and 147, including construction, has been verified for this well. An Internal (Part I)

Mechanical Integrity (MI) and External (Part II) MI **is required for reauthorization** of injection activities for this well.

4. <u>Waiver of Permit Requirements</u>.
The conditions in this permit may be altered in accordance with the provisions under 40 CFR Section 144.16 (b). This regulation applies to wells which inject through or above an underground source of drinking water. Under this provision, the Director may authorize a well or project with less stringent requirements for operation, monitoring, and reporting than required in 40 CFR Section 144.52 or Part 146 to the extent that the reduction in requirements will not result in an increased risk of movement of fluids into an underground source of drinking water. The radius of endangering influence (or cone of influence) when computed must be smaller or equal to the radius of the well. **A waiver may be requested no sooner than one (1) year after the well has continued operation under this permit renewal. The Permittee may submit multiple applications due to changing site conditions.**

The Permittee shall discuss with the Director how they will obtain the following: the Radius of Endangering Influence (or cone of influence), Injection calibration data, Pressure Fall Off data, and viscosity of injection fluid measurements. Once the Permittee and the Director form a mutual agreement, the Permittee shall provide a work plan to the EPA for approval describing the Radius of Endangering Influence calculation, Injection Test, and Pressure Fall Off Test results, **thirty (30) days** prior to performing the test. All test results and calculations shall be provided to the Director **within sixty (60) days** of completion of the activity. If the Director determines that the requirements of 40 CFR Section 144.16(b) have been achieved, the conditions of this permit may be modified in accordance with the procedure identified in Part III, Section B.1.

5. <u>Conversions</u>
The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class I injection well to a non-Class I well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

6. <u>Permittee Change of Address</u>
Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the applicant. Any such claim shall be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and

- Information which deals with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. <u>Duty to Comply</u>.
   The Permittee shall comply with all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and re-issuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. <u>Penalties for Violations of Permit Conditions</u>.
   Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Continuation of Expiring Permits.

a) Duty to Reapply. If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee shall submit a complete application for a new permit **at least one hundred eighty (180) days** before this permit expires.

b) Permit Extensions. The conditions of an expired permit may continue in force in accordance with 5 U.S.C. 558(c) until the effective date of a new permit, if:

(i) The Permittee has submitted a timely application which is a complete application for a new permit; and

(ii) The Director, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

c) Enforcement. When the Permittee is not in compliance with the conditions of the expiring or expired permit the Director may choose to do any or all of the following:

(i) Initiate enforcement action based upon the permit which has been continued;
(ii) Issue a notice of intent to deny the new permit. If the permit is denied, the owner or operator would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit;
(iii) Issue a new permit under Part 124 with appropriate conditions; or
(iv) Take other actions authorized by these regulations.

d) State Continuation. An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State has primary enforcement authority. A State authorized to administer the UIC program may continue either EPA or State-issued permits until the effective date of the new permits, if State law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State-issued new permit.

4. Need to Halt or Reduce Activity not a Defense.
It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. Duty to Mitigate.
The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. Proper Operation and Maintenance.
The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. Duty to Provide Information.
The Permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry.
The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:

a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

b) Have access to and copy, at reasonable times, any records that shall be kept under the conditions of this permit;

c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA any substances or parameters at any location.

9. Records of the Permit Reauthorization/Issuance Application.
The Permittee shall maintain records of all data required to complete the permit reauthorization application and any supplemental information submitted for a period of **five (5) years** from the effective date of this permit. This period may be extended by request of the Director at any time.

10. Signatory Requirements.
All reports or other information requested by the Director shall be signed and certified according to 40 CFR 144.32.

11. Reporting of Noncompliance.

a) Anticipated Noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted **no later than thirty (30) days** following each schedule date.

c) Twenty-four Hour Reporting.

(i) The Permittee shall report to the Director any noncompliance which may endanger health or the environment. Any information shall be provided orally **within twenty-four (24) hours** from the time the Permittee becomes aware of the circumstances by telephoning EPA at **(303) 312-6211 (during normal business hours)** or at **(303) 293-1788 (for reporting at all other times)**. The following information shall be included as information, which shall be reported orally **within twenty-four (24) hours**:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to an underground source of drinking water; and/or

(B) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided **within five (5) days** of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

d) Oil Spill and Chemical Release Reporting. The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

e) Other Noncompliance. The Permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E.11.(c)(ii) of this permit.

f) Other Information. Where the Permittee becomes aware that he failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall submit such facts or information **within two (2) weeks** of the time such information became known to him.

APPENDIX A CONSTRUCTION PROCEDURE

The Woods No. 3 (MWD-1) shall be constructed, as follows:

Elevation: 6,717 ft. (GR)

Conductor Casing:
13-3/8 inch casing, casing set at 0 – 40 ft., 20 inch hole, cement from 0 – 40 ft. (40 sxs. ready mix cement)

Surface Casing:
9-5/8 inch casing, casing set at 0 – 1,424 ft., 12-1/4 inch hole, cement from 0 – 1,424 ft. (450 sxs. Howco Lite and 200 sxs. Class B and C cement)

Production Casing:

Remedial Action: Perforate the well casing at 4,780 ft. Squeeze cement through the perforation in the 7 inch casing to place cement behind pipe between the interval 1,374 ft. – 4,780 ft.

7 inch casing, casing set at 0 – 8,142 ft., 8-3/4 inch hole, cement from 1,374 ft. – 4,780 ft. and 5,850 ft. – 8,142 ft. (750 sxs. Howco Lite; 350 sxs. Class B; and 200 sxs. Howco Lite)

Top of Cement (TOC): 1,374 ft.

Total Depth: 8,886 ft. (Based upon driller interpretation this well may be drilled to 8,900 ft.)

Plug Back Total Depth: none

Perforations: 5,935 ft. – 6,170 ft. ; 6,760 ft. – 7,060 ft. (squeezed perforations)
Leadville/Ouray Perforations: 7,836 ft. – 7,911 ft. (open perforations)
7,933 ft. – 7,962 ft. (squeezed)
Devonian (Elbert)/Cambrian: 8,142 ft. – 8,886 ft. (open hole)

Tubing: 4-1/2 inch plastic coated tubing or similar type, set at 7,782 ft. or within 100 ft. of the top open perforation

Packer: 5 ½ inch x 4 ½ inch or similar type, set at 7,736 ft. or within 100 ft. of the top open perforation

All of the depths provided above are approximate measurements. Following the receipt of approval on the Final Permit and the completion of construction activities the operator shall submit a Well Completion Form and revised well rework construction diagram which shall be subject to EPA's approval.

KINDER MORGAN

PROPOSED WELL SCHEMATIC

Well Name:	MWD #1	State:	Colorado	SPUD:	8/8/1977
API # :	05-083-6193	County:	Montezuma	Initial Completion:	11/11/1977
Section:	18 Township: 37N	Range:	17W	Deepening Start Date:	7/26/2010
Surface Hole:	2900' FSL & 600' FEL	KB:	17'	Deepening RR Date:	8/19/2010
Elevation:	6717' (GR)				

NOT TO SCALE

Conductor Casing

Size	13-3/8 in	
Set at	40 ft	Conductor @ 40 ft
Wt.	75 ppf	Grade K-55
Hole Size	20 in	

Surface Casing

Size	9-5/8 in	
Set at	1424 ft	
Wt.	36 ppf	Grade K-55
Hole Size	12-1/4 in	
Est. T.O.C.	surface ft	

9-5/8" Csg Shoe @ 1424 ft

Production Casing

Size	7.0 in	
Wt.	26 ppf	Grade K-55 from surface to 131 ft
Wt.	20 ppf	Grade K-55 from 131 to 3276 ft
Wt.	23 ppf	Grade K-55 from 3276 to 5150 ft
Wt.	26 ppf	Grade SS-95 from 5150 to 7354 ft
Wt.	23 ppf	Grade SS-95 from 7354 to 8142 ft
Hole Size	8-3/4 in	
Est. T.O.C.	5850 ft	

Injection Tubing

4 1/2" Plastic Coated Tubing
5 1/2" x 4 1/2" packer
10' 4 1/2" 13Cr

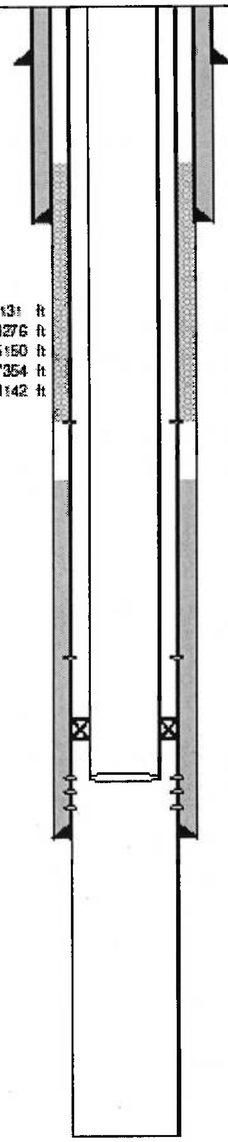
Formation Tops

Chinle	1746	ft
Cutler	2718	ft
Upper Hermosa	4790	ft
Desert Creek	5744	ft
Paradox	5934	ft
Molas	7682	ft
Leadville	7776	ft
Elbert	8122	ft
Pre-Cambrian	8883	ft

Packer @ 7736 ft

7" Csg Shoe @ 8142 ft

TD @ 8886 ft



Conductor Cement

cement with ready-mix to suface
40 sxs cement to surface

Surface Cement

Date Cemented: 8/11/1977
Load : 450 sxs, Howco Lite
Yield 1.84 at 12.7 ppg
Tail : 200 sxs, Class BC at 15.6 lb/gal
Yield 1.18 at 15.9 ppg
Note : Full returns w/ 80 bbls cmt to surface

Prod Cement

Date Cemented: 9/4/1977
Stage 1: 750 sxs Howco Lite
Stage 2: 350 sxs Class B
Stage 3: 200 sxs Howco Lite
Est. TOC: 5850' from CBL 9/20/77
Note : Bumped plug floats held.

Remedial Cement

Perforate @ 4780'. Squeeze cement to 1374'.
Proposed TOC: 1374'

Perforations

Squeezed Perfs:
5935'-6170', 6760' - 7060'

7776' Top of Leadville
7898' Upper Leadville
Perforations: (1 shot/ft)
7836', 7837', 7841'
7842, 7872', 7873', 7878', 7883', 7887', 7899'
7900', 7907', 7908', 7909', 7910', 7911'

7932' Middle Leadville
Squeezed Perfs:
7933', 7934', 7944', 7948', 7949'
7950', 7951', 7960', 7961', 7962'

7966' Lower Leadville
8046' Ouray

Open Peforations

Selectively perforated based on log indications

APPENDIX B MONITORING AND REPORTING

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section E, for detailed requirements for observing, recording and reporting these parameters.

OBSERVE CONTINUOUSLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)
QUARTERLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid pH
QUARTERLY	
REPORT	Each month's minimum, maximum and average injection pressure (psig)
	Each month's minimum, maximum and average annulus pressure (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Each month's Annulus Fluid Level
	Written results of annulus injected fluid analysis
	Sources of all fluids injected during the year

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to Appendix D – LOGGING AND TESTING REQUIREMENTS.

APPENDIX C PLUGGING & ABANDONMENT PLAN

The revised PLUGGING AND ABANDONMENT PLAN submitted by the applicant is considered to be protective of all USDWs. The revised plan is incorporated into this Permit and is binding on the Permittee.

After receiving approval from the Colorado Oil and Gas Conservation Commission, and notifying the appropriate Regional EPA office, the permitted injection well will be plugged and abandoned in accordance with the following PLUGGING AND ABANDONMENT PLAN.

PLUG NO. 1: (Leadville-Ouray, Undifferentiated Devonian (Elbert) and Cambrian Injection Zone, 7,726 ft. – 8,886 ft.) – Set a cement retainer at approximately 7,776 ft. inside the 7 inch casing. Set a 1,110 ft. cement plug below the cement retainer from 7,776 ft. to 8,886 ft. inside the 7 inch casing. Set a 50 ft. cement plug above the cement retainer from 7,726 ft. – 7,776 ft. inside the 7 inch casing.

PLUG NO. 2: (Paradox Salt Confining Zone, 5,884 ft. – 5,984 ft.) – Set a 100 ft. balance plug at approximately 5,884 ft. to 5,984 ft. inside the 7 inch casing.

PLUG NO.3: (Honaker Trail, 4,680 ft. – 4,780 ft.) – Set a 100 ft. balance plug at approximately 4,680 ft. to 4,780 ft. inside the 7 inch casing. .

PLUG NO. 4: (Cutler top, 2,668 ft. – 2,768 ft.) – Set a 100 ft. balance cement plug at approximately 2,668 ft. to 2,768 ft. inside the 7 inch casing.

PLUG NO. 5: (Chinle top, 1,696 ft. – 1,796 ft.) –Set a 100 ft. balanced cement plug at approximately 1,696 ft. to 1,796 ft. inside the 7 inch casing.

PLUG NO. 6: (9.625" casing shoe, 1,374 ft. – 1,474 ft.) –Set a 100 ft. balanced cement plug from approximately 1,374 ft. to 1,474 ft. inside the 7 inch casing.

PLUG NO. 7: (13.375" shoe, surface – 100 ft) – Set a cement plug from the surface to approximately 100 ft. inside and behind the 7" casing.
Cut off the wellhead below the surface casing. Install P&A marker.

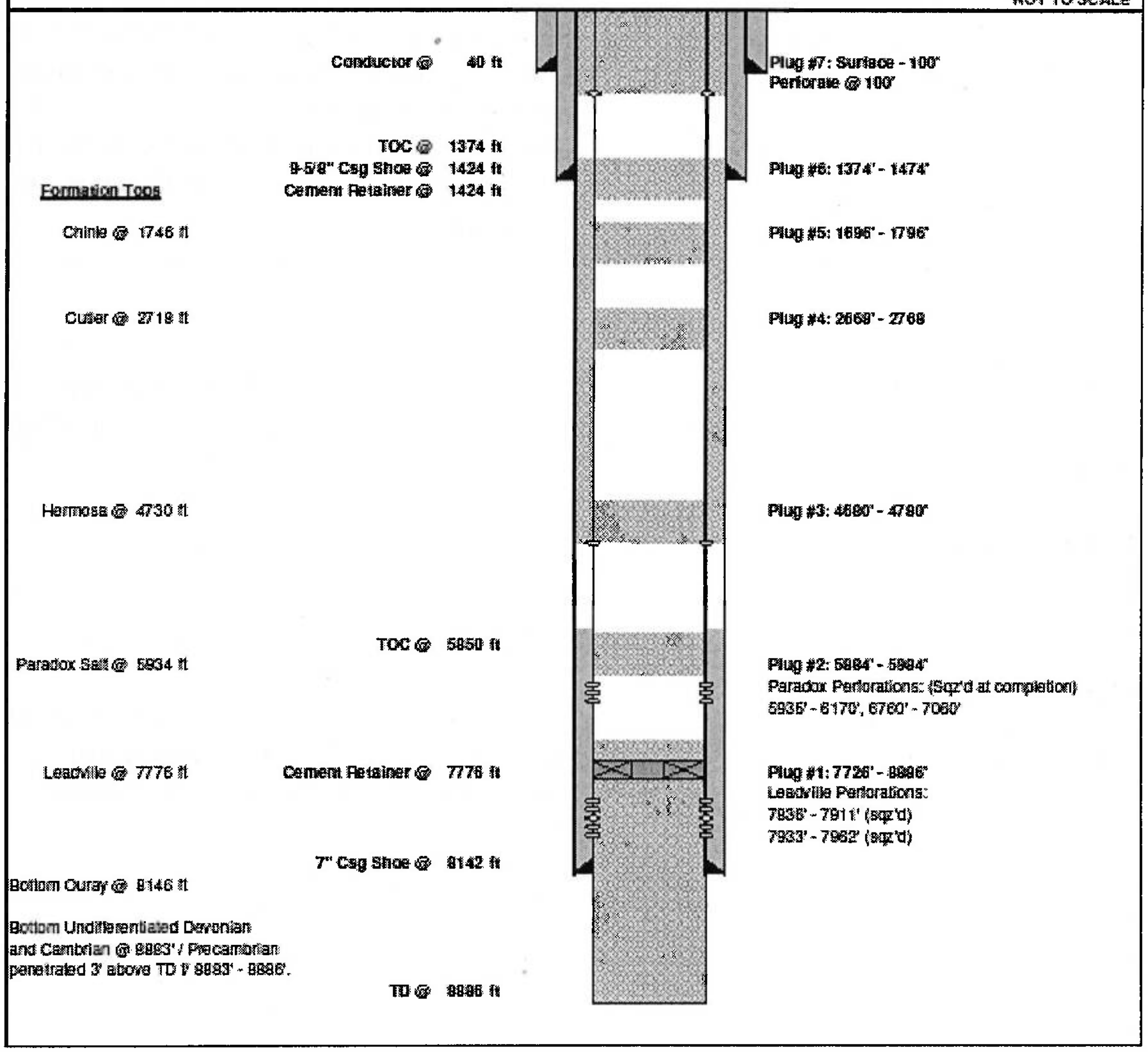
Note: Cemented areas shall be tagged. Class C or similar type cement shall be used to Plug and Abandon the Woods No. 3 (MWD-1) well. Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal should be used during plugging operations, and should remain between plugs in the well after cement plug placement.

KINDER MORGAN

Proposed P&A Schematic

Well Name:	MWD #1	State:	Colorado	SPUD:	8/8/1977
API # :	05-083-6193	County:	Montezuma	Initial Completion:	11/11/1977
Section:	16 Township: 37N	Range:	17W	Deepening Start Date:	7/26/2010
Surface Hole:	2900' FSL & 600' FEL	KB:	17'	Deepening RR Date:	8/19/2010
Elevation:	5717' (GR)				

NOT TO SCALE



APPENDIX D LOGGING & TESTING REQUIREMENTS

Logs.
Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

TYPE OF LOG	DATE DUE
Fracture Finder Log for open hole section (below 8,142 ft.) of MWD-1 well	Shall be performed and submitted to the EPA Director **prior to receiving authorization to commence injection.**
Cement Bond Log for MWD-1 well	Shall be performed and submitted to the EPA Director **prior to receiving authorization to commence injection.**
See the List of Tests Below for Additional Testing and Logging Requirements	

Tests.
Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

Well Name: MWD-1

TYPE OF TEST	DATE DUE
Internal (Part I) Mechanical Integrity Test may be demonstrated with a pressure test using fluid or gas.	Shall be performed prior to receiving authorization to commence injection and **at least every five (5) years** after the last successful demonstration of Mechanical Integrity.

External (Part II) Mechanical Integrity Test shall be demonstrated with either Option 1: a Temperature Log (TL) or Noise Log or Option 2: with the Temperature Log and supplemental Radioactive Tracer Survey *Additional Requirements:* • TL injection must occur either on a vacuum or at the MAIP • RTS injection for the slug shot test may be performed at normal operating pressures but injection for the time drive tess must be performed at the MAIP	Shall be performed within ninety (90) and one hundred eighty (180) days following the receipt of a limited authorization to inject and **at least every five (5) years** after the completion of the last successful Part II External demonstration of Mechanical Integrity.
Pore Pressure Measurements	Shall be performed and submitted to the EPA Director **prior to receiving authorization to commence injection.**
Step Rate Test w/a minimum of six (6) steps and a maximum injection pressure of 1,000 psi and Fall Off Test.	Shall be performed to verify the permitted MAIP **within ninety (90) and one hundred eighty (180) days** following the receipt of a limited authorization to inject.
Fall Off Test and Calibration Data	Shall be performed **within one (1) year** after the well has received final authorization to inject and annually, thereafter. An alternate testing procedure may be approved by the Director following the completion and review of Interference Test Data.
Interference Test	An optional Interference Test may be performed after two years of operation and the completion of a second Pressure Fall Off Test with the collection of field data. Interference Pressure Fall Off Test procedures must be submitted for EPA's approval at least three (3) weeks prior to performing the test. The Director may approve an alternate date to perform an Interference Test.

Water Quality Analysis for each of the following: Leadville, Ouray, Undifferentiated Devonian , and Cambrian Formations	An analysis of the formations' water quality for the list of parameters in Appendix G shall be performed and submitted to the Director **prior to receiving authorization to commence injection.**
Compatibility Analysis of the injectate and the formation fluids	An evaluation of the compatability of the injectate to the formation fluids shall be provided **prior to receiving authorization to commence injection.**
Stimulation Program	Shall notify the Director within **thirty (30) days** for approval prior to performing the activity.

APPENDIX E OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:
Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below:

Well Name: Woods No. 3 (MWD-1)
Maximum Allowed Injection Pressure: 1,000 psi

INJECTION ZONE(S):
Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A.4. Specific injection perforations can be found in APPENDIX A.

Woods No. 3 (MWD-1)

FORMATION NAME	APPROVED INJECTION INTERVAL (ft)
Leadville	7,776 – 8,046
Ouray	8,046 – 8,122
Undifferentiated Devonian and Cambrian	8,122 – 8,900

FORMATION NAME	PERFORATED INTERVAL (ft)
Leadville-Ouray	7,836 – 7,951
	8,012 – 8,062
Undifferentiated Devonian and Cambrian	8,145 – 8,900 (open hole)

ANNULUS PRESSURE:
The annulus pressure shall be maintained at/or below twenty-five (25) psi gauge as measured at the wellhead. If this pressure cannot be maintained at/or below twenty-five (25) psi, the Permittee shall follow the procedures listed under Part II, Section D.5 of this permit to reduce annulus pressure.

MAXIMUM INJECTION VOLUME:
There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed the limit shown above.

APPENDIX F CORRECTIVE ACTION

No Corrective Action is required.

APPENDIX G ANALYTICAL EVALUATION

pH	Oil and Grease
Conductivity	Total Coliform
Specific Gravity	Total Organic Halogens
Temperature	Bicarbonate
Total Dissolved Solids	Carbonate
Total Organic Carbon	Hydroxide
Radium 226	Total Fecal Coliforms
Radium 228	Corrosivity
Gross Alpha	Hexavalent Chromium
Gross Beta	Nitrite
Total Alkalinity (As CaCO3)	Nitrate
Chloride	Iron
Nitrate+Nitrite	Flouride
Sulfate	
Calcium	
Magnesium	
Potassium	
Sodium	
Barium	
Chromium	
Strontium	

STATEMENT OF BASIS

KINDER MORGAN CO_2 COMPANY
MWD-1 MAJOR MODIFICATION
MONTEZUMA COUNTY, CO

EPA PERMIT NO. CO10789-00420

CONTACT: Linda Bowling
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-UIC
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6254

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for ten (10) years or unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41

PART I. General Information and Description of Facility

Kinder Morgan CO_2 Company
17801 Hwy 491
Cortez, CO 81321

on

November 1, 2010

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

MWD-1
2,800 ft. FSL & 600 ft. FEL, SE NE, S16, T37N, R17W
Montezuma County, CO

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

Kinder Morgan CO_2 Company proposes deepening the well to convert it from a former Leadville Ouray injection well, to a Leadville, Ouray, Undifferentiated Devonian, and Cambrian Formations injection well.

Kinder Morgan CO_2 Company LP (Kinder Morgan) is involved in the extraction of oil and gas from subsurface reservoirs. Kinder Morgan has determined that the naturally occurring carbon dioxide (CO_2) can be produced and economically used as an enhanced oil recovery agent.

The CO_2 field is leased under provisions of standard oil and gas leases from the Bureau of Land Management (BLM) and private parties. Existing and proposed production operations (from approximately 14 wells in the Leadville and Ouray Formations) are expected to result in the recovery of naturally-occurring gases consisting of 98.37% carbon dioxide (CO_2), 1.38% nitrogen (NO_2) and 0.25% methane (CH_4). These produced gases shall be piped to a cluster facility where free water is separated out using gravity separation. The liquid and vapor CO_2 shall be treated with Diethylene Glycol (DEG) and transported to a central facility where the CO_2 is vaporized and the liquid water and DEG are separated.

This permit allows the non-commercial injection of the process-produced, nonhazardous McElmo Dome and Doe Canyon Fields' Leadville and Ouray Formations waste water into the Leadville, Ouray, Undifferented Devonian and Cambrian injection zones for disposal.

The Permit will expire on October 31, 2009 or 10 years from the effective date of the last re-issuance permit (2009) or upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the State of Colorado unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a State Permit. This permit has been issued for **ten (10) years**, unless terminated. It is the Permittee's responsibility to read and understand all provisions of this permit. The permit will **expire at midnight ten (10) years after the effective date**

of the re-issued permit, or upon delegation of primary enforcement responsibility for the UIC 1422 Program to the State of Colorado, unless that State has adequate authority and chooses to adopt and enforce this permit as a State permit.

This modification does not contain an extension for the current expiration date of October 31, 2009. According to 40 CFR 144.36, paragraph b – Duration of Permits, "Except as provided in §144.37, the term of a permit shall not be extended by modification beyond the maximum duration specified in this section.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1
WELL STATUS / DATE OF OPERATION

CONVERSION WELLS

Well Name	Well Status	Date of
MWD-1	Existing	N/A

PART II. Permit Considerations (40 CFR 146.24)

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
MWD-1

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS	ZONE TYPE
Dakota	Sandstone and shale	0	658	< 10,000 mg/l	USDW
Morrison	Sandstone and mudstone	658	750	< 10,000 mg/l	USDW
Bluff	Sandstone	750	1110	< 10,000 mg/l	USDW
Summerville	Sandstone and mudstone	1110	1225	< 10,000 mg/l	USDW
Entrada	Sandstone	1225	1304	< 10,000 mg/l	USDW
Carmel	Siltstone, shale, limestone	1304	1324		Confinement
Navajo	Sandstone	1324	1390	< 10,000 mg/l	USDW
Kayenta	Sandstone and mudstone	1390	1400	< 10,000 mg/l	USDW
Wingate	Sandstone	1400	1746	< 10,000 mg/l	USDW
Chinle	Siltstone, sandstone, shale, and limestone	1746	2650	< 10,000 mg/l	USDW
Moenkopi	Siltstone and sandstone	2650	2718	< 10,000 mg/l	USDW
Cutler	Sandstones and conglomerates	2718	4430	6,420 mg/l	USDW
Honaker Trail	Sandstones, limestones, and shales	4430	5934	Unknown	Confinement
Paradox Salt	Impermeable salt, dolomites and shales	5934	7546	Little to no water	Confinement
Pinkerton Trail	Salt, dolomites and Shales	7546	7682	Little to no water	Confinement

Molas	Siltstones, sandstones, limestones, and shales	7682	7776	Little to no water	Confinement
Leadville	Limestones	7776	8046	20,000 mg/l – 200,000 mg/l	Injection zone
Ouray	Limestone and Dolomite	8046	8122	20,000 mg/l – 200,000 mg/l	Injection zone
Undifferented Devonian and Cambrian	**Undifferentiated Devonian** Shale, limestone, sandstone, and siltstone **Cambrian Formation** Siltstone, dolomite, and shale	8122	8900	20,600 mg/l	Injection zone
Precambrian	Crystalline	8900	11883	Little to no water	Confinement

The Well Completion reports which contain the formations' names and depths of formations starting from the surface to the top of the Devonian were obtained from the Colorado Oil and Gas Conservation Commission database. The data for the Cambrian formation was obtained from additional information submitted by the applicant. Some formation depths have been adjusted to account for geological interpretation variations. It has been our policy to first consider values submitted in Well Completion or Recompletion Reports and Logs which are obtained from the State of Colorado's database first and then to consider additional data certified by a Professional Geologist. The total dissolved solids values and lithology descriptions have been obtained from the permit application, additional data submitted by the permittee, and the reference document Ground Water Atlas of the United States, Segment 2. Water quality data will be collected to confirm the total dissolved solids content in the Undifferentiated Devonian and Cambrian Formations. A Fracture Finder Log will be run prior to receiving an authorization to inject to identify potential pathways and to comply with the regulatory requirement under 40 CFR 146.12(d)2.

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

TABLE 2.2
INJECTION ZONES
MWD-1

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Leadville	7,776	8,046	20,000-200,000	TBD		
Ouray	8,046	8,122	20,000-200,000	TBD		
Undifferentiated Devonian and Cambrian	8,122	8,900	20,600	TBD		

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed

The depths of the injection intervals may vary due to logging based upon information submitted in a future Completion or Recompletion Form which will be required prior to the receipt of an authorization to inject.

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3

TABLE 2.3
CONFINING ZONES

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS	ZONE TYPE
Carmel	Siltstone, shale, limestone	1304	1324	Unknown	Confinement
Honaker Trail	Sandstones, limestones, and shales	4430	5934	Unknown	Confinement
Paradox Salt	Impermeable salt, dolomites and shales	5934	7546	Little to no water	Confinement
Pinkerton Trail	Salt, dolomites and Shales	7546	7682	Little to no water	Confinement
Molas	**Siltstones, sandstones, limestones, and shales**	**7682**	**7776**	**Little to no water**	**Confinement**
Precambrian	**Crystalline**	**8900**	**11883**	**Little to no water**	**Confinement**

The bolded zones are the upper (Molas) and lower (Precambrian) confining zones for the proposed injection interval.

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS	ZONE TYPE
Dakota	Sandstone and shale	0	658	< 10,000 mg/l	USDW
Morrison	Sandstone and Mudstone	658	750	< 10,000 mg/l	USDW
Bluff	Sandstone	750	1110	< 10,000 mg/l	USDW
Summerville	Sandstone and Mudstone	1110	1225	< 10,000 mg/l	USDW
Entrada	Sandstone	1225	1304	< 10,000 mg/l	USDW
Navajo	Sandstone	1324	1390	< 10,000 mg/l	USDW
Kayenta	Sandstone and Mudstone	1390	1400	< 10,000 mg/l	USDW
Wingate	Sandstone	1400	1746	< 10,000 mg/l	USDW
Chinle	Siltstone, sandstone, shale, and limestone	1746	2650	< 10,000 mg/l	USDW
Moenkopi	Siltstone and Sandstone	2650	2718	< 10,000 mg/l	USDW
Cutler	Sandstones and conglomerates	2718	4430	6,420 mg/l	USDW

STATEMENT OF BASIS

KINDER MORGAN CO_2 COMPANY
MWD-1 MAJOR MODIFICATION
MONTEZUMA COUNTY, CO

EPA PERMIT NO. CO10789-00420

CONTACT: Linda Bowling
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-UIC
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6254

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for ten (10) years or unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41

PART I. General Information and Description of Facility

Kinder Morgan CO_2 Company
17801 Hwy 491
Cortez, CO 81321

on

November 1, 2010

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

MWD-1
2,800 ft. FSL & 600 ft. FEL, SE NE, S16, T37N, R17W
Montezuma County, CO

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

Kinder Morgan CO_2 Company proposes deepening the well to convert it from a former Leadville Ouray injection well, to a Leadville, Ouray, Undifferentiated Devonian, and Cambrian Formations injection well.

Kinder Morgan CO_2 Company LP (Kinder Morgan) is involved in the extraction of oil and gas from subsurface reservoirs. Kinder Morgan has determined that the naturally occurring carbon dioxide (CO_2) can be produced and economically used as an enhanced oil recovery agent.

The CO_2 field is leased under provisions of standard oil and gas leases from the Bureau of Land Management (BLM) and private parties. Existing and proposed production operations (from approximately 14 wells in the Leadville and Ouray Formations) are expected to result in the recovery of naturally-occurring gases consisting of 98.37% carbon dioxide (CO_2), 1.38% nitrogen (NO_2) and 0.25% methane (CH_4). These produced gases shall be piped to a cluster facility where free water is separated out using gravity separation. The liquid and vapor CO_2 shall be treated with Diethylene Glycol (DEG) and transported to a central facility where the CO_2 is vaporized and the liquid water and DEG are separated.

This permit allows the non-commercial injection of the process-produced, nonhazardous McElmo Dome and Doe Canyon Fields' Leadville and Ouray Formations waste water into the Leadville, Ouray, Undifferented Devonian and Cambrian injection zones for disposal.

The Permit will expire on October 31, 2009 or 10 years from the effective date of the last re-issuance permit (2009) or upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the State of Colorado unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a State Permit. This permit has been issued for **ten (10) years**, unless terminated. It is the Permittee's responsibility to read and understand all provisions of this permit. The permit will **expire at midnight ten (10) years after the effective date**

of the re-issued permit, or upon delegation of primary enforcement responsibility for the UIC 1422 Program to the State of Colorado, unless that State has adequate authority and chooses to adopt and enforce this permit as a State permit.

This modification does not contain an extension for the current expiration date of October 31, 2009. According to 40 CFR 144.36, paragraph b – Duration of Permits, "Except as provided in §144.37, the term of a permit shall not be extended by modification beyond the maximum duration specified in this section.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1
WELL STATUS / DATE OF OPERATION

CONVERSION WELLS

Well Name	Well Status	Date of
MWD-1	Existing	N/A

PART II. Permit Considerations (40 CFR 146.24)

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
MWD-1

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS	ZONE TYPE
Dakota	Sandstone and shale	0	658	< 10,000 mg/l	USDW
Morrison	Sandstone and mudstone	658	750	< 10,000 mg/l	USDW
Bluff	Sandstone	750	1110	< 10,000 mg/l	USDW
Summerville	Sandstone and mudstone	1110	1225	< 10,000 mg/l	USDW
Entrada	Sandstone	1225	1304	< 10,000 mg/l	USDW
Carmel	Siltstone, shale, limestone	1304	1324		Confinement
Navajo	Sandstone	1324	1390	< 10,000 mg/l	USDW
Kayenta	Sandstone and mudstone	1390	1400	< 10,000 mg/l	USDW
Wingate	Sandstone	1400	1746	< 10,000 mg/l	USDW
Chinle	Siltstone, sandstone, shale, and limestone	1746	2650	< 10,000 mg/l	USDW
Moenkopi	Siltstone and sandstone	2650	2718	< 10,000 mg/l	USDW
Cutler	Sandstones and conglomerates	2718	4430	6,420 mg/l	USDW
Honaker Trail	Sandstones, limestones, and shales	4430	5934	Unknown	Confinement
Paradox Salt	Impermeable salt, dolomites and shales	5934	7546	Little to no water	Confinement
Pinkerton Trail	Salt, dolomites and Shales	7546	7682	Little to no water	Confinement

Molas	Siltstones, sandstones, limestones, and shales	7682	7776	Little to no water	Confinement
Leadville	Limestones	7776	8046	20,000 mg/l – 200,000 mg/l	Injection zone
Ouray	Limestone and Dolomite	8046	8122	20,000 mg/l – 200,000 mg/l	Injection zone
Undifferented Devonian and Cambrian	**Undifferentiated Devonian** Shale, limestone, sandstone, and siltstone **Cambrian Formation** Siltstone, dolomite, and shale	8122	8900	20,600 mg/l	Injection zone
Precambrian	Crystalline	8900	11883	Little to no water	Confinement

The Well Completion reports which contain the formations' names and depths of formations starting from the surface to the top of the Devonian were obtained from the Colorado Oil and Gas Conservation Commission database. The data for the Cambrian formation was obtained from additional information submitted by the applicant. Some formation depths have been adjusted to account for geological interpretation variations. It has been our policy to first consider values submitted in Well Completion or Recompletion Reports and Logs which are obtained from the State of Colorado's database first and then to consider additional data certified by a Professional Geologist. The total dissolved solids values and lithology descriptions have been obtained from the permit application, additional data submitted by the permittee, and the reference document Ground Water Atlas of the United States, Segment 2. Water quality data will be collected to confirm the total dissolved solids content in the Undifferentiated Devonian and Cambrian Formations. A Fracture Finder Log will be run prior to receiving an authorization to inject to identify potential pathways and to comply with the regulatory requirement under 40 CFR 146.12(d)2.

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

TABLE 2.2
INJECTION ZONES
MWD-1

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Leadville	7,776	8,046	20,000-200,000	TBD		
Ouray	8,046	8,122	20,000-200,000	TBD		
Undifferentiated Devonian and Cambrian	8,122	8,900	20,600	TBD		

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed

The depths of the injection intervals may vary due to logging based upon information submitted in a future Completion or Recompletion Form which will be required prior to the receipt of an authorization to inject.

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3

TABLE 2.3
CONFINING ZONES

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS	ZONE TYPE
Carmel	Siltstone, shale, limestone	1304	1324	Unknown	Confinement
Honaker Trail	Sandstones, limestones, and shales	4430	5934	Unknown	Confinement
Paradox Salt	Impermeable salt, dolomites and shales	5934	7546	Little to no water	Confinement
Pinkerton Trail	Salt, dolomites and Shales	7546	7682	Little to no water	Confinement
Molas	**Siltstones, sandstones, limestones, and shales**	**7682**	**7776**	**Little to no water**	**Confinement**
Precambrian	**Crystalline**	**8900**	**11883**	**Little to no water**	**Confinement**

The bolded zones are the upper (Molas) and lower (Precambrian) confining zones for the proposed injection interval.

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS	ZONE TYPE
Dakota	Sandstone and shale	0	658	< 10,000 mg/l	USDW
Morrison	Sandstone and Mudstone	658	750	< 10,000 mg/l	USDW
Bluff	Sandstone	750	1110	< 10,000 mg/l	USDW
Summerville	Sandstone and Mudstone	1110	1225	< 10,000 mg/l	USDW
Entrada	Sandstone	1225	1304	< 10,000 mg/l	USDW
Navajo	Sandstone	1324	1390	< 10,000 mg/l	USDW
Kayenta	Sandstone and Mudstone	1390	1400	< 10,000 mg/l	USDW
Wingate	Sandstone	1400	1746	< 10,000 mg/l	USDW
Chinle	Siltstone, sandstone, shale, and limestone	1746	2650	< 10,000 mg/l	USDW
Moenkopi	Siltstone and Sandstone	2650	2718	< 10,000 mg/l	USDW
Cutler	Sandstones and conglomerates	2718	4430	6,420 mg/l	USDW

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
MWD-1

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Conductor	17.5	13.375	0 - 40	0 - 40
Surface	12.25	19.625	0 – 1,424	0 –1,424
Longstring	8.75	7	0 – 8,142	1,374 – 4,780 5,850 – 8,142

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

The well construction description has been obtained from the Colorado Oil and Gas Conservation Commission's database and additional data submitted by the applicant to supplement the Major Modification Application.

Casing and Cementing (TABLE 3.1)
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

The applicant shall place cement behind pipe (longstring or production casing) between the depths of 1,374 ft to 4,780 ft. The addition of cement behind pipe shall be performed to protect underground sources of drinking water. Additional cement will be squeezed behind pipe to also adhere to regulatory requirements under 40 CFR 147.305(d).

Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

The placement depth of both the tubing and packer have been identified in Appendix A of the draft permit

Tubing-Casing Annulus (TCA)
The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Kinder Morgan is required to maintain the annulus pressure between 0 psi and 25 psi or use the procedures in Guidance No. 35 to address exceedences. The annulus between the tubing and the casing shall be filled with water treated with corrosion inhibitors and oxygen scavengers.

Monitoring Devices
The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

The applicant shall be required to monitor the maximum injection pressure and record results in accordance with the conditions of the permit's appendix D. An inspector will perform visual inspections of the well, pressure levels, ground surface, and well head.

The permittee shall use the specific criteria in Part II Section E.1 to define significant change in the parameters: pH, Total Dissolved Solids, and specific gravity. A comprehensive water analysis shall be obtained for the injection fluid whenever a significant change in the identified parameters is observed.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
none					

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

No wells were identified in the Area of Review. No corrective action is required.

Area Of Review
Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence.

The 1/4 mile radius used for the area of review is considered to be adequate. There are no non-freshwater or freshwater artificial penetrations identified within a ¼ mile radius of the proposed injection well. No additional facilities including surface water bodies, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults were identified by Kinder Morgan in the MWD-1 well application, within a ¼ mile radius.

Corrective Action Plan
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

No Corrective Action is required as there are no wells within the area of review.

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES

Formation Name	Depth Used to Calculate	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Leadville	7776	0.56	1000
Ouray	7776	0.56	1000
Undifferentiated Devonian	7776	0.56	1000
Cambrian	7776	0.56	1000

The applicant has requested and is permitted to perform a Step Rate Test with a minimum of 6 rate steps and a maximum allowed injection pressure of 1,000 psi. A final Fracture Gradient and Maximum Allowed Injection Pressure shall be established once the applicant completes the Step Rate Test.

Approved Injection Fluid
The approved injection fluid is limited to

(a) spent sulfamic acid (2-8%) neutralized to a pH of 5 to 9 with soda ash or baking soda. This solution will also include a surfactant, a corrosion inhibitor and ammonium bifluoride;

(b) acetic acid;

(c) diethanolamine (DEA);

(d) coolant drain-off (50% water, 50% diethylene glycol);

(e) associated treatment chemicals, (e.g., antifreeze, corrosion inhibitor, and bacteria inhibitor);

(f) potassium permanganate in potable water;

(g) diethylene glycol;

(h) produced/processed fluids; and

(i) any non-hazardous fluids associated with field and plant development, operation and maintenance:

Compatibility analysis shall be performed prior to receiving authorization to commence injection. Compatibility analysis shall be performed to evaluate any impacts caused by injection into the proposed injection zones. Appendix G is a list of analysis to be performed on the formation fluids. It is based upon previous analysis performed on nearby wells and regulatory requirements.
The annulus fluid will consist of a solution of water treated with corrosion inhibitor and oxygen scavenger.

Injection Pressure Limitation
Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)

sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

- *fg = 0.56 (this fracture gradient was obtained from Woods No. 3, MWD-1 previous Step Rate Test)*

- *sg = specific gravity = 1.010 g/cc for the injectate*

- *d = 7776 ft = depth at which the Leadville Formation is encountered*

A Step Rate Test shall be performed within ninety (90) and one hundred eighty (180) days following the receipt of a limited authorization to begin injection. 40 CFR 146.12 – Construction requirements paragraph (e) requires the fracture pressure to be determined or calculated during the construction phase of the well.

The Step Rate Test shall be performed at or below the maximum pressure of 1,000 psi with a minimum of six (6) rate steps. A maximum pressure of 1,000 psi has been estimated based on calculations for previous Kinder Morgan CO_2 Company wells in Montezuma County, Colorado not to initiate fractures. A fracture finder log shall be provided for EPA's review prior to receiving authorization to start injection. Both surface and downhole (using a downhole pressure bomb or similar type tool) pressure will be measured during the test duration.

Stimulation Program – Kinder Morgan CO_2 Company shall submit a detailed stimulation procedure if stimulation is determined to be needed. Kinder Morgan anticipates that if stimulation is required the procedure will involve a conventional acid soak with HCL and/or a clean out using coiled tubing or a conventional work string.

Injection Volume Limitation
Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

No volume limits are placed in the permitting conditions because the injection zones will not be USDWs. The applicant shall obtain water quality samples from the injection zones which contain total dissolved solids values to ensure that the formation(s) are not USDWs.

Mechanical Integrity (40 CFR 146.8)
An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

The applicant is required to perform a Part I and Part II MIT as follows:

- *Part I, Shall be performed prior to receiving authorization to inject (or a limited authorization to inject) and **at least every five (5) years** after the last successful demonstration of Mechanical Integrity. Testing requirements for Part I (Internal) MI testing for Class I nonhazardous wells is further discussed in EPA Region 8, Ground Water Section Guidance No. 39, Pressure testing injection wells for Part I (Internal) Mechanical Requirement.*

- *Part II, Shall be performed within one (1) year following the receipt of a final authorization to inject and **at least every five (5) years** after the last successful demonstration of Mechanical Integrity. Federal regulation 40 CFR 146.8(c)1 requires the absence of significant fluid be determined with either a temperature or noise log. Therefore, a temperature log with a supplemental radioactive tracer survey may be used to perform Part II (External) Mechanical Integrity Testing.*

  Because this well generally operates on a vacuum, the applicant shall perform tests as follows:
  - *Temperature Logs shall be performed by injecting on a vacuum*
  - *Radioactive Tracer Surveys shall be performed by conducting the slug test portion on a vacuum but the time drive portion of the test must be performed by injecting at the maximum allowable injection pressure.*

The MAIP for the well may be adjusted following the review of conditions (i.e. pressure) used to run the test and a review of the results of the test.

- *Pressure Fall Off Tests shall be performed within a 180 day limited authorization period and annually thereafter. Both surface and downhole (with a downhole pressure bomb or similar type tool) pressure will be measured during the test duration.*

  The applicant may request to perform an Interference Test after two years of operation and the completion of two Pressure Fall Off Tests or at an alternate timeframe approved by the Director. The EPA Director shall consider and make a determination regarding the future use of an alternate annual Pressure Fall Off Test procedure after reviewing available data..

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, injection flow rate and cumulative fluid volume, and the maximum and average value for each must be determined for each month. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520-13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix C of the Permit.

The injection well plugging and abandonment plan described in Appendix C is considered to be adequate for protecting overlying USDWs. Kinder Morgan may resubmit the Plugging and Abandonment Plan with updated depths once the well has been re-constructed. The permittee also is required to comply with other applicable federal state and local plugging regulations.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility
The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

A demonstration of Financial Responsibility in the amount of $104,000 has been provided.

The Director may revise the amount required, and may require the permittee to obtain and provide updated estimates of costs for plugging the well according to the approved Plugging and Abandonment Plan.

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Federal Law (40 CFR § 144.4)

EPA has determined that issuance of Permit Number CO10789-00420 for the Woods No. 3 (MWD-1) injection well is in compliance with the laws, regulations, and orders described at 40 C.F.R. § 144.4, including the National Historic Preservation Act (NHPA) and the Endangered Species Act (ESA).

NHPA Review

The Colorado State Historic Preservation Officer submitted a letter dated February 14, 2012, "Proposed Kinder Morgan Injection Wells HWD-2, MWD-1, and DWD-1, Montezuma and Dolores Counties, Colorado (CHS #61375)." The Colorado SHPO believes that a finding of no historic properties affected (rather than no adverse effect) is appropriate for the proposed project.

Other organizations such as local government, the Bureau of Land Management (BLM), and several tribes identified on a list suggested by the Colorado State Historic Preservation Office have been contacted. We are currently responding to all comments received. Nevertheless, we have not received any complaints regarding the project. Only inquiries for more information about the process that is used to issue permits and acknowledgement of the receipt of the requests submitted to all potential stakeholders.

ESA Review

The Fish and Wildlife Service has reviewed data submitted by EPA regarding Kinder Morgan's anticipated no adverse impacts expected to Threatened and Endangered Species and Habitat in the proposed area. They did not object to the project. But they have addressed a concern that the pipeline for the well DWD-1 will be installed near a road that serves as a winter concentration area for the Elk. They have advised that construction activities be avoided between December 1 – April 15 inorder to not impact Elk in the area.

Other organizations such as local government, the Bureau of Land Management (BLM), and several tribes identified on a list suggested by the Colorado State Historic Preservation Office have been contacted. We are currently responding to all comments received. Nevertheless, we have not received any complaints regarding the project. Only inquiries for more information about the process that is used to issue permits and acknowledgement of the receipt of the requests submitted to all potential stakeholders.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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FEB 19 2014

Ref: 8P-W-UIC

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1001 Louisiana Street, Suite 1000
Houston, Texas 77002

Re: Minor Modification No. 2
Adjustment of MAIP Modification No. 2
Kinder Morgan CO_2 Company, UIC 1422 Class I
Nonhazardous Woods No. 3, MWD-1 well
EPA UIC Permit CO10789-00420
Montezuma & Dolores Counties, Colorado
API No.: 05-083-06193

Dear Mr. Wuerth:

This letter transmits a Minor Modification for the Environmental Protection Agency Region 8 Underground Injection Control Program Permit CO10789-00420 to increase the maximum allowable injection pressure (MAIP) for the MWD-1 well to 15 psig.

Pursuant to the Code of Federal Regulations Title 40 (40 CFR) Section 144.41(e), the EPA is modifying this Permit to increase the MAIP from 0 psig to 15 psig. Should you desire to increase the MAIP or alter the conditions of the well in the future, additional tests and/or logs may be required. Kinder Morgan should notify the EPA of its request to increase the pressure in accordance with the Final Permit requirements.

If you have any questions regarding this authorization, please call Linda Bowling of my staff at (303) 312-6254.

Sincerely,

Douglas Minter
Acting UIC Unit Chief
Office of Partnerships and Regulatory Assistance

cc: E-mails only:

Coy Bryant
Kinder Morgan CO_2 Company

Michael Hannigan
Kinder Morgan CO_2 Company

Bence Close
GeoSyntec Consulting

Bob Koehler, UIC Supervisor
Colorado Oil and Gas Conservation Commission

John Pecor
Bureau of Land Management

Mark Weems
Colorado Oil and Gas Conservation Commission

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

FEB 06 2014

Ref: 8P-W-UIC

Jim Wuerth, President
Kinder Morgan CO_2 Company
1001 Louisiana Street, Suite 1000
Houston, Texas 77002

Re: Minor Modification No. 1
Adjustment of MAIP Modification No. 1
Kinder Morgan CO_2 Company, UIC 1422 Class I
Nonhazardous Woods No. 3, MWD-1 well
EPA UIC Permit CO10789-00420
Montezuma & Dolores Counties, Colorado
API No.: 05-083-06193

Dear Mr. Wuerth:

This letter transmits a Minor Modification for the Environmental Protection Agency Region 8 Underground Injection Control Program Permit CO10789-00420 to reduce the maximum allowable injection pressure (MAIP) for the MWD-1 well to 0 psi. Kinder Morgan CO_2 Company, LP (Kinder Morgan) was notified of this change in an Authorization to Inject letter dated December 18, 2013. This additional notification is provided to complete our internal records process for the MAIP update.

Pursuant to the Code of Federal Regulations Title 40 (40 CFR) Section 144.41(e), the EPA is modifying this Permit to reduce the MAIP from 1,000 psi to 0 psi. The MAIP is reduced because the Radioactive Tracer Survey, dated September 13, 2013, demonstrated adequate cement behind pipe at a pressure of 0 psi. Should you desire to increase the MAIP or alter the conditions of the well in the future, additional tests and/or logs may be required. Kinder Morgan should notify the EPA of its request to increase the pressure in accordance with the Final Permit requirements.

If you have any questions regarding this authorization, please call Linda Bowling of my staff at (303) 312-6254.

Sincerely,

Douglas Minter
Acting UIC Unit Chief
Office of Partnerships and Regulatory Assistance

cc: E-mails only:

Coy Bryant
Kinder Morgan CO_2 Company

Michael Hannigan
Kinder Morgan CO_2 Company

Bence Close
GeoSyntec Consulting

Denise Onyskiw, UIC Supervisor
Colorado Oil and Gas Conservation Commission

John Pecor
Bureau of Land Management

Mark Weems
Colorado Oil and Gas Conservation Commission

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Ref: 8P-W-UIC

JUN 04 2014

Jim Wuerth, President
Kinder Morgan CO_2 Company
1001 Louisiana Street, Suite 1000
Houston, Texas 77002

Re: Minor Modification No. 3
Modification No. 1- Change of Logging and Testing Requirements, Kinder Morgan CO_2 Company, UIC Class I Woods No. 3 (MWD-1) well
EPA UIC Permit No. CO10789-00420
Montezuma County, Colorado
API No.: 05-083-06193

Dear Mr. Wuerth:

This letter transmits a Minor Modification to alter conditions in Appendix D- Logging and Testing Requirements for the Woods No. 3 (MWD-1) well authorized under the Environmental Protection Agency Region 8 Underground Injection Control Program Permit No. CO10789-00420, effective date June 21, 2012.

Pursuant to the Code of Federal Regulations Title 40 (40 CFR) Section 144.41(e), the EPA is modifying this Permit to require that all Part II (External) Mechanical Integrity Tests are performed at maximum allowable injection pressure (MAIP) and to remove the optional Interference Test condition. These logging and testing requirements are altered so that Kinder Morgan CO_2 Company may operate with permit conditions equivalent to other Region 8 UIC operators. Furthermore, Part II MITs must be performed at MAIP to adequately test cement behind pipe at MAIP. These changes will allow additional monitoring of the disposed fluids in an effort to protect underground sources of drinking water. The altered minor modification for Appendix D - Logging and Testing Requirements are enclosed.

If you have any questions regarding this authorization, please call Linda Bowling of my staff at (303) 312-6254.

Sincerely,

Craig Boomgaard

for Douglas Minter
Acting UIC Unit Chief
Office of Partnerships and Regulatory Assistance

Enclosure

cc: E-mails only:

Coy Bryant
Kinder Morgan CO_2 Company

Michael Hannigan
Kinder Morgan CO_2 Company

Bence Close and Aaron Weeger
GeoSyntec Consulting

Bob Koehler, UIC Supervisor
Colorado Oil and Gas Conservation Commission

John Pecor
Bureau of Land Management

Mark Weems
Colorado Oil and Gas Conservation Commission

WOODS NO. 3 (MWD-1) WELL MINOR MODIFICATION NO. 3
EPA PERMIT NO. CO10789-00420

A modification to the above listed permit is made pursuant to Title 40 of the Code of Federal Regulations, Section 144.41(e). Changes made to Appendix D Logging and Testing Requirements of the Final Permit with an effective date of June 21, 2014. This modification only changes the conditions for Part II MITs and Interference Tests.

ORIGINAL LANGUAGE: (Permit, Page x)

Well Name: MWD-1

TYPE OF TEST	DATE DUE
External (Part II) Mechanical Integrity Test shall be demonstrated with either Option 1: a Temperature Log (TL) or Noise Log or Option 2: with the Temperature Log and supplemental Radioactive Tracer Survey *Additional Requirements:* TL injection must occur either on a vacuum or at the MAIP RTS injection for the slug shot test may be performed at normal operating pressures but injection for the time drive tess must be performed at the MAIP	Shall be performed within ninety (90) and one hundred eighty (180) days following the receipt of a limited authorization to inject and **at least every five (5) years** after the completion of the last successful Part II External demonstration of Mechanical Integrity.
Interference Test	An optional Interference Test may be performed after two years of operation and the completion of a second Pressure Fall Off Test with the collection of field data. Interference Pressure Fall Off Test procedures must be submitted for EPA's approval at least three (3) weeks prior to performing the test. The Director may approve an alternate date to perform an Interference Test.

MODIFIED LANGUAGE: (Permit, Page x)
Is modified to:

Well Name: MWD-1

TYPE OF TEST	DATE DUE
External (Part II) Mechanical Integrity Test shall be demonstrated with either Option 1: a Temperature Log (TL) or Noise Log or Option 2: with the Temperature Log and supplemental Radioactive Tracer Survey	Shall be performed within ninety (90) and one hundred eighty (180) days following the receipt of a limited authorization to inject and **at least every five (5) years** after the completion of the last successful Part II External demonstration of Mechanical Integrity. All tests must be performed at the Maximum Allowable Injection Pressure.
Interference Test	This optional test condition is removed.